4.0 Electricity Rates and Equity: Potential For Cost-shifting.

ESSB 6560 directs the agencies to examine:

The potential for cost-shifting among customer classes and among customers within the same class, and strategies available to minimize inappropriate cost shifts.

This section addresses the issue of cost-shifting in four ways:

1) We discuss "cost-shifting" and average-cost rate-making in general. This discussion yields a working definition of the term "cost-shifting" and a scope for our examination of cost-shifting potential.
2) We describe a number of developments and circumstances in the electricity service industry in Washington that either could, or are, causing cost-shifts to happen.
3) We evaluate a subset of these circumstances to estimate what the potential magnitude of cost-shifting might be.
4) We examine a number of actions or policies that could affect and minimize the potential for cost-shifts.

4.1. Cost-shifting: Definition and Study Scope

Cost-shifting is a relevant issue when the price for a monopoly service is established as a cost-based rate through regulation or some other administratively or legislatively established directive. When prices are set administratively, the rate-setting body may have within its authority the ability to shift cost responsibility from one set of customers to another. Most electricity service in Washington continues to be priced through administrative or regulatory process at the state or local level. The changing context and factors affecting those processes will be the focus of this section. As a working definition of "cost-shifting" for the purposes of this analysis we will use:

> *An administrative or regulatory decision to change rates charged to customer classes or customers within a class that causes those customers to be responsible for costs they are not responsible for in rates today and which were formerly paid by other customers or customer classes.*

In a fully competitive market, prices are not set administratively. In theory, when a market is efficient and effective for all buyers and sellers there is no party that can cause costs to be shifted from one buyer to the detriment of another. For a market to be efficient and effective there must be multiple sellers competing for every buyer, and multiple buyers competing for every seller, and all parties must have reasonably equal access to capital and information. In practice, many markets are not fully efficient and competitive and prices can significantly diverge from underlying cost for individuals or groups of buyers. While this does not constitute administrative cost-shifting as we have defined it, the result could none-the-less be unfair price differentiation or price discrimination.

While we do not discount the potential for price discrimination or differentiation in markets that are not fully competitive, most retail electricity services in Washington have rates that are set administratively and not by markets. Consequently, we have confined our study to administrative cost-shifting. Moreover, we do not attempt to examine the validity of existing rates nor how prices and services might change in more competitive markets. The definition stated above is applied to administrative rate-setting decisions that are being made today about costs currently being recovered in rates, as well as to decisions that may be made in the future about costs that are yet to be incurred.

Some parties argue that the current level of rates may involve improper or inequitable allocations of cost and that these constitute cost-shifts that should require rates to be realigned with costs. This section does not examine or critique the past decisions of local rate-making authorities or the UTC that have led to the current distribution of cost-responsibility in rates. We believe this to be consistent with the statutory direction to study “the potential for cost-shifting.”

The legislation also directs us to examine “inappropriate” cost-shifting. Rate-setting based on the average costs to serve a class of customers always involves the exercise of judgment in the translation of both common and direct costs into average rates. There are no uniform and objective criteria for determining whether cost-shifts, or discrepancies between rates and the costs to serve individual or classes of customers, are “appropriate”. There is no state law that establishes how rates are to be based on costs, or that they be exclusively based on costs. Rates are directed by statute to be “fair, just, and reasonable” and one of the factors that must be considered is whether or not they are discriminatory or preferential. These are the criteria that are considered and balanced by state and local rate-setting bodies when judging whether rates are appropriate and whether any cost-shifting implicit within them is appropriate.

4.2. How are electricity rates based on costs?

Electricity rates in Washington have been, and by and large continue to be, based on a utility’s aggregate costs to provide service to all of its customers. The revenue necessary to cover the utility’s total costs is determined by either the UTC (for investor-owned utilities) or local commissions, governments, or cooperative boards for the consumer-owned utilities. This “revenue requirement” includes both direct costs — those that can be identified with particular categories of customers — and common costs — those that cannot be identified with any particular customer or category of customers.

The revenue requirement is assigned to the various customer classes to recover the common costs and the direct costs that are incurred by the utility to provide service to those customer classes. This is accomplished in a “cost of service study”. Rates charged to the customers are developed based on this assigned revenue requirement such that the rate for each unit of service (kWh, kW of demand, or customer account) recovers the *average* cost of serving that customer class.

Calculation of the utility's overall revenue requirement (its overall cost of providing service) is a relatively straightforward matter. But, the assignment of costs to customer classes and ultimately to individual customers is more a matter of judgment than a matter of indisputable fact. Utility service involves a combination of power generation, power delivery, and administrative services that in many cases cannot be definitively assigned to a particular customer class, or particular customers within that class. No cost-of-service study can be totally accurate in its assignment to the customer classes of direct costs because the functions of utility service cannot be totally isolated (e.g. transmission and delivery services involve some aspects of generation services). And, common costs like administration and overhead can only be *allocated* to the customer classes because they are common to all the services. Even within customer classes, rates based on average cost mean that some customers pay more than their actual cost of service and some pay less. Consequently, rate-making based on average costs does not perfectly reflect the costs of service — either for the customer classes, or for individual customers within a rate class.

Recognizing these challenges in cost of service studies, rates are reviewed and approved based on the expert judgment of local officials, coop boards, or the Commissioners of the UTC. This judgment is exercised to achieve equity between customer classes and between customers within a class. However, whether they can be measured or not, average rates frequently involve some level of transfer, subsidy, or cost-shift between customer classes and among customers within a class. So long as rates are based on the average cost to provide service, some customers can argue justifiably that they are paying more than the actual cost to serve them and that other customers are paying less. Arguments about the size and fairness of these "inequities" generally make up a good portion of the debate that occurs during rate cases, at both the state and local levels.

The foregoing discussion makes clear that the issue of cost-shifting is not new. It has historically been a factor in, and a source of controversy surrounding, average-cost rate-making and will continue to be so for all electricity services for which rates are administratively set. Any time rates are changed the potential exists for cost-shifts to occur. The context in which these rate decisions are made *is* constantly changing, however. This changing context leads to change in the kind of pressures rate-setting bodies face when they make judgments about how and from whom costs should be recovered. The next sections describe these changing conditions and identify areas where pressure to shift costs might occur. It is important to recognize that cost-shifting pressures occur in both the wholesale power sector, including transmission, and in the retail local distribution utility sector. The latter category is clearly affected by the former. We have described these conditions separately because many of the issues at the wholesale level are not easily affected by state or local actions. Those at the retail level may be.

4.3. Developments and Trends Affecting Potential for Cost-Shifting: Wholesale Power and Transmission Sector

The most important and far-reaching factor affecting the conditions under which electricity rates are set and which might cause cost-shifts is significant change in the market structure for power generation. Beginning slowly in 1978 with the passage of the federal Public Utility Regulatory Policy Act (PURPA), and rapidly accelerating after passage of the federal Energy Policy Act in 1992, the power generation sector of the electricity industry has undergone a transformation. It has been transformed from a generally closed market dominated by utilities, to a much more open and competitive market involving both utility and non-utility generators, as well as commodity brokers and other market-makers. This has been accomplished primarily through changes in federal regulation of the wholesale power and transmission sectors. The implications of these changes for state and local utility rate-setting and the potential for cost-shifting are profound in the following areas:

- Services and pricing in a commodity market for electricity,
- Transmission access and pricing, and
- The policies of the BPA.

4.3.1. Commodity Market for Electricity

The advent of competition in the electric power generation sector was designed to lead to a commodity market for electricity generation. Since 1992, and particularly with the introduction of published price indices by national newspapers, futures contracts by the NYMEX, and the California Power Exchange in 1998, this commodity market has steadily grown. We noted in an earlier section the significant increase in the volume of bulk, generally wholesale, power transactions in this newly developed market. Competition among suppliers in the bulk power market may maximize the aggregate economic efficiency of bulk power generation. The average price of power from a more efficient power system may be lower, but it is likely also to be more volatile and could actually increase in some regions. While the development of a competitive bulk power market does not directly lead to any specific cost-shifting, it does change the conditions under which utility rates are set and these changed conditions could lead to cost-shifting in at least three ways.

First, the development of this market has led to better and more accessible information about the price at which bulk electricity is available — to utilities and to individual customers who have the means to purchase directly from the market or at market-based prices. It has also led to an expansion of the kinds of services and pricing options available to utilities and these customers. These prices and services may differ from the average cost of power supplied by utilities from plants built and contracts negotiated in the past to meet service obligations to customer loads. When coupled with wider access to the transmission system, the conditions exist for some customers to either leave the average cost system or to press for rates based on market prices rather than average costs. We will describe how these conditions might affect the retail market structure and retail cost-shifting in Washington in the section on retail market trends below.

Second, wholesale electricity price levels were quite low — less than 2 cents per kWh — early in the advent of a more open generation market in both the West and the rest of the country. This is the price for short-term “electricity commodity” before the costs of reliable transport, delivery, metering, billing and system management are included. Recently the market price of short-term electricity has become increasingly volatile with substantial price spikes. In the West, prices have been higher by a half to a full cent this year than those seen in 1995 and 1996 and have seen spikes of over a dollar per kWh. In the Eastern U.S. prices went as high as 7 dollars per kWh early in the summer of 1998. Price volatility is a normal characteristic of commodity markets and is a key factor necessary to attract new investment in production facilities. However, this volatility does represent a substantial risk, which could be distributed differently among customers in the future than resource cost risk is currently distributed in rates. [1]

The third issue involves the relationship between Washington's relatively low-cost power generation resources and Washington's electricity customers. Preceding sections have described how the generation resources now serving Washington customers are lower in cost than the cost of generation nationally, or more importantly throughout the rest of the West. Independent analyses also have shown that the cost of generation serving Washington also is likely to be lower than market clearing prices in California and other Western power marketplaces.[2] Washington's utilities might be able to command a higher price for power they generate if they were to sell in these markets at market price rather than to Washington customers at cost. If this value is not preserved for Washington customers, the potential exists for some, or perhaps all, Washington customers to see increased rates as power originally priced at cost is sold at market rates. This makes development of mechanisms to retain the value of these resources for Washington customers particularly important. A number of recent analyses have made estimates of the amount by which Washington's electricity costs might increase if power were simply market-priced with no provisions to benefits from low-cost resources for Washington customers. The Oak Ridge National Laboratory estimated that, in the absence of policies to retain the benefits of low-cost generation, the states in the Northwest Power Pool could see power generation prices rise 1.1 cents/kWh.[3] This translates to about 22 percent on average retail electricity rates in Washington. The Clinton Administration analysis of the effect of power market deregulation estimated that rates in the Northwest could decrease slightly (5.6 percent) by the year 2010, but only if policy makers took steps to capture the benefits of low-cost federal, public and private generation[4]. Other studies have made a similar point.[5] A recent study by the Northwest Power Planning Council identified that the regional value of cost-based federal power rates, when judged against market set power rates, is from 0 to 9 $billion over the next 20 years, depending on the measures undertaken to meet fish restoration obligations.[6]

4.3.2. Transmission Access and Pricing

The Federal Energy Regulatory Commission (FERC) issued new rules in 1996 (Order 888) to implement the direction of the Energy Policy Act to achieve open access to transmission services for all generation suppliers. These rules govern the transmission tariffs utilities must offer to anyone wishing to transmit power over their facilities. The rules require that all investor-owned utilities must make their transmission facilities accessible to all parties who may wish to use them on the same terms and conditions under which the utility itself uses the facilities. While the FERC rules do not apply directly to non-jurisdictional utilities such as federal, municipal or other publicly-owned utilities, reciprocity requirements are included which mean that a non-jurisdictional utility is not eligible to use the open access tariff of an IOU unless it offers a comparable open access tariff. The FERC also has established principles to govern the way in which rates for open access transmission tariffs are to be calculated. These transmission access and pricing policy developments could result in either direct or indirect pressure to shift costs in several ways.

4.3.2.1. Broadening of FERC Jurisdiction and Implications for Utility Bypass

The broadened access to bulk transmission systems, when coupled with a growing competitive generation market, establishes conditions that may encourage bypass of utility distribution systems. This is particularly true given the FERC's assertion in Order 888 that it has jurisdiction over the pricing, and terms and conditions of service for "retail transmission." These conditions could lead to some retail customers, even those served at relatively low voltage levels, gaining direct access to the bulk transmission system under terms and conditions established by FERC rather than the state or its local jurisdictions. This could lead to either retail distribution facility or power costs being left with the retail utility by departing customers that become FERC jurisdictional for much of their service. These costs could be shifted to other customers if the state or local regulators determine it is necessary to do so. The UTC has joined with ten other states and the National Association of Regulatory Utility Commissioners (NARUC) to appeal the FERC's Order in federal court to overturn what the states claim is an unauthorized jurisdictional incursion on state and local authority.

4.3.2.2. Implications of FERC Pricing Principles

Turning to transmission rates, the rates currently paid by the customers of Washington's investor-owned utilities include transmission and delivery costs that assign a portion of costs to customer classes based on the volume of use (throughput) over the transmission and delivery facilities serving those customer classes. FERC pricing principles assign all transmission and delivery costs to peak usage of the facilities and none to the volume of use. The difference between these two approaches is that customers whose usage varies through time (mainly residential and small commercial customers) are assigned a higher proportion of costs under the FERC method. This change in pricing methodology, coupled with FERC's requirement that utilities pay the same transmission rate to serve native load customers that they charge other users of their systems, means that a cost shift could occur between the industrial and residential classes over the next few years. Based on the transmission component of rates for Washington's largest investor-owned utility (Puget Sound Energy), the magnitude of this effect could be as large as $3 to 4 million annually.[7] This amounts to one-half to one percent of Puget Sound Energy's residential rates. This cost-shift may be difficult for the UTC to prevent given the FERC's jurisdiction over transmission pricing. In fact, the shift could be larger if FERC prevails in its jurisdictional claim noted above.

On the other hand, FERC jurisdiction over retail transmission could have the opposite impact for customers of Washington utilities that purchase a large share of their power or transmission from the Bonneville Power Administration. FERC jurisdiction over BPA's transmission system could shift costs among BPA customers in at least two ways. First, FERC's preferred methodology for pricing wholesale transmission service uses twelve monthly coincident peaks as a billing determinant for demand-based transmission charges. BPA has historically used fundamentally a single, non-coincident peak. Because the FERC methodology is much less favorable to high-load factor customers such as the direct service industries (DSIs), costs could be shifted to these customers from low load factor customers such as small utilities with a high proportion of residential load.

Second, FERC's preferred pricing methodology would allow BPA to include the costs of certain facilities in its transmission rates that have historically been recovered through power rates. These include facilities necessary to integrate generators into the regional grid (called "generation integration" facilities), as well as the Colstrip lines and the Southern Intertie. Rolling these costs into transmission rates would shift them from BPA's power customers to its transmission customers. It might also reduce the likelihood that BPA would have to rely on a transition cost-recovery mechanism such as a rate adjustment clause to cover a shortfall in power revenues.

Eliminating or limiting the application of "postage stamp" rates on the BPA system is another potential cause of cost shifting for BPA customers. "Postage stamp" rates means that transmission on the system is priced at the same rate regardless of the facilities used or distances involved. This is important to many small and rural utilities in the state because it keeps the cost of transmitting power to their systems low. While FERC's Order 888 principles call for "a single, unbundled, grid-wide tariff that applies to all eligible users", FERC has allowed a great deal of experimentation in order to promote the formation of Independent System Operators (ISOs). Eliminating postage stamp rates on the BPA system might better reflect the actual cost of transmission to individual utilities, but it could cause a significant shift of costs to small and rural utilities.

4.3.2.3. Formation of Independent System Operators (ISO)

As the FERC continues to restructure the wholesale power and transmission sectors, it has encouraged the establishment of ISOs. These organizations have many purposes, including: separation of utility power marketing commercial interests from transmission interests; establishment of more efficient access to transmission capacity; more organized control of transmission operation to enhance reliability; and the opportunity to improve the efficiency of transmission pricing. All of these have as an ultimate purpose the improved efficiency and effectiveness of a competitive power generation market.

One of the ways ISO formation might produce a more efficient power market is through elimination of the need to pay multiple transmission tariffs to cross multiple systems. This "pancaking" of transmission rates may restrain economic activity by raising the cost of transmitting power, simply because of dispersed ownership of the transmission grid. However, eliminating pancaked transmission rates would require broad scale transmission pricing changes to develop a single, region-wide tariff that recovers all the costs of each utility's transmission facilities. Such a uniform, single tariff may result in significant shifting of transmission costs. The implementation of an ISO in the Northwest could have the consequence of shifting transmission costs both to Washington from other states and shifting responsibility for transmission costs among Washington utilities.

Cost-shifting emerged as a significant issue during the discussions surrounding IndeGO (Independent Grid Operator), the proposal for an independent system operator for the Northwest and Rocky Mountain regions which was developed by a number of utilities during 1996 and 1997. A number of different pricing methodologies were considered during the IndeGO negotiations, each of which would have ramifications for cost-shifting. The greatest amount of cost-shifting would occur if transmission costs for all utilities in the region were simply averaged into a single, region-wide, postage stamp rate. This is the pricing methodology favored by FERC in the ISO principles that it laid out in Order 888. This methodology would result in costs being shifted to Washington utilities from states such as Montana, Colorado and Wyoming, in addition to costs being shifted among utilities within the state. Some Washington utilities could see their transmission costs increase by 50 percent, or 0.244 per kWh, under a region-wide, postage stamp rate, while others would see decreases of as much as 10%.

The IndeGO parties rejected a region-wide, postage stamp rate because this level of cost-shift was considered unacceptable by utilities participating in the negotiations. Instead, an alternative called the "Allocated Area Rate" pricing methodology was developed which averaged utilities' transmission costs with neighboring utilities within an "Access Pricing Area", instead of across the entire region. This method shifted fewer costs than a region-wide postage stamp rate, and largely eliminated the shifting of costs from one state to another. However, it still resulted in transmission cost increases of 25 percent, or 0.14 per kWh, for several Washington utilities, and cost decreases of a similar magnitude for others. These cost shifts played a large role in the decision by the region's utilities not to go forward with the IndeGO proposal at this time.

FERC has requested enhanced authority to require utility participation in ISOs, and a number of bills have been introduced in Congress which would grant such authority.[8] In recent speeches, FERC Commissioners have indicated they believe FERC already has the authority to order participation in ISOs by jurisdictional utilities.[9] FERC is likely to issue rules clarifying this issue at some point in the next few months. At this point it is not possible to predict what form of ISO may evolve in the Northwest, or how it will ultimately price transmission.

4.3.3. The Bonneville Power Administration

Aside from the transmission pricing issues already described, the BPA's rates for power have also been strongly affected by the development of a competitive wholesale power market. BPA is directed by the Pacific Northwest Electric Power Planning and Conservation Act — Public Law 96-501 (Regional Power Act) to establish its rates according to a very complex set of rules. Any change to BPA power rates, or to the distribution of costs among those rates is traditionally attended by protest from one regional interest or another. As BPA develops power rates and policies affecting access to federal power resources for the next five to twenty years the potential for costs and risks to be shifted are substantial. For purposes of this study we describe three areas: contingent cost-recovery mechanisms; availability of federal power sales; and the low-density discount. Other areas also present the potential for cost shifting including general transmission transfer agreements and BPA power rate structure changes.

4.3.3.1. Contingent cost-recovery mechanism

BPA is required to collect sufficient revenue to repay its debt to the federal Treasury (roughly $7 billion for power facilities) and its third-party debt of roughly $7 billion. The third-party debt is principally for the Washington Public Power Supply System nuclear projects Number 1, 2, and 3. The agency is also required to fund the operation of the power system and its responsibilities for fish and wildlife programs. If BPA's costs to fulfill all these responsibilities rise to a level that causes its rates to exceed the otherwise available price of power in the wholesale market it will begin to lose sales and fail to meet all its obligations. While recent projections made by the Northwest Power Planning Council indicate the probability of this situation occurring is relatively low, it is possible, particularly between 2001 and 2015, after which much of the WPPSS debt will have been repaid.[10] To plan for such a difficult situation, BPA will very likely need to establish a "contingent cost-recovery mechanism." This is a means for it to collect revenue from some source other than power sales to fulfill its obligations. A number of different approaches are currently under discussion. Any such mechanism could lead to cost shifts *if* it is ever implemented and *if* it fails to collect revenue equitably from all regional parties, including public and private utilities and direct service industries. The magnitude, probability, and distribution of these cost-shifts are impossible to predict at this point in time.

4.3.3.2. Availability of Federal Power

BPA will establish new contracts for power sales from the Federal Columbia River Power System (FCRPS) in 1999. These contracts will cover periods beginning in 2001. The amount of power available to be sold from the FCRPS is limited and BPA will establish the framework and criteria under which this limited power will be made available to Northwest utilities and direct service industries. Currently, FCRPS power is sold to meet the net-requirements of public utilities under the public preference provisions of the Bonneville Project Act and the Regional Act. Power is also sold, when requested, to meet the net-requirements loads of investor-owned utilities under the provisions of the Regional Act. And finally, the direct service industries purchase power under BPA's contracting authority granted under the Regional Act. Residential and small farm customers of the investor-owned utilities also receive benefits from the FCRPS through the Residential Exchange Program, authorized by the Regional Act. The only group of Northwest electricity customers who do not have access to some form of direct benefit from the federal power system are the industrial and commercial customers of investor-owned utilities.

Debate has occurred over the last year regarding how, under the Residential Exchange Program or otherwise, economic benefits of the FCRPS will be accessible to the residential and small farm customers of investor-owned utilities. Ultimate resolution of this issue will involve claims of cost-shifts by all parties. FCRPS benefits received by the residential customers of some of the investor-owned utilities (mainly Puget Sound Energy) are substantial, as much as $50 million/year. If actual power is allocated by BPA (rather than cash transfers) to these residential customers, insufficient FCRPS power will be available to serve the direct service industries.[11] Limiting the amount of federal power available to serve these industrial loads means that they will need to use their recently acquired access to BPA transmission services to purchase power on the market, perhaps at prices higher than FCRPS costs. If BPA arranges to provide benefits in the form of cash payments to the investor-owned utility residential customers, or purchases additional power to meet these loads, either the public utilities or the direct service industries will likely claim that new costs have been shifted to them. The nature of cost-shifts resulting from BPA's power allocation policies and rate making will not be known for certain before the end of 1999. BPA and the region are working hard to develop a framework for selling federal power that is principled and balances all interests.

4.3.3.3. Low Density Discount

Also as directed by the Regional Act, BPA has historically offered a discounted power rate to low-density utility systems (rural systems characterized by few customers per mile of distribution line). In 1996, this discount amounted to nearly $10 million for low-density utilities in Washington.[12] Depending on whether and how BPA decides to continue this rate discount, small rural utilities in Washington could see cost-shifts that, while not large in absolute magnitude, would none-the-less significantly affect rates on their relatively small systems.

4.4. Trends Affecting Potential for Cost-Shifting: Retail Power Sales and Distribution Sector

Given these major changes in the "upstream" sectors of generation and transmission, the nature of Washington's retail electricity market structure is undergoing change as well. New retail services and flexible pricing, as well as projects to bypass utility distributions can lead to potential cost shifts in a number of areas including:

- Average power costs embedded in utility rates;
- Average delivery system costs embedded in utility rates;
- Individual customer metering and system management;
- Taxes (both revenue and property) included in power rates;
- Conservation, renewable resource, and low-income program costs.

The following sections discuss trends and issues affecting potential cost-shifting in each of these areas. Where possible and practical we have provided an estimate of the potential magnitude of cost-shifts that might occur under a set of described circumstances and assumptions.

4.4.1. New Retail Services and Flexible Pricing: Power Supply

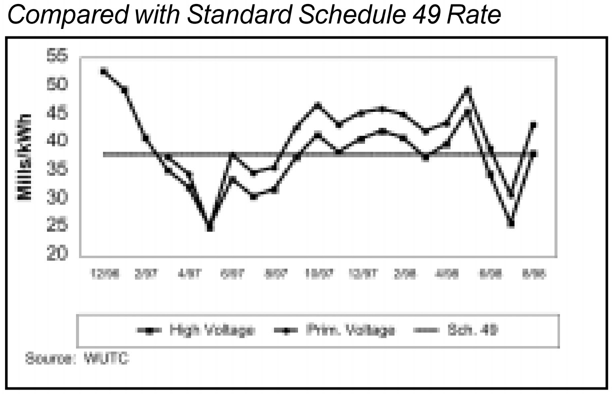
The development of a competitive generation market, accessibility of bulk power price information, and the broader availability of access to the transmission system have increased the level of interest among some customers and customer classes in obtaining power services at market rates rather than average cost utility tariffs. For the most part, these are large-volume-load industrial or commercial customers. Competitive power suppliers in the wholesale market are likewise eager to make retail power sales to these large loads. As a consequence, utilities have responded with a number of new services and pricing arrangements that vary from market based pricing of the energy component of service to fully separating delivery service and offering it apart from energy sales (retail wheeling or direct access). We noted increasing variety of service offerings and non-traditional tariffs in Section 1.0.

Data submitted by the utilities indicate that in 1997 roughly 8.4 million MWh of annual sales to industrial or large commercial customers were made under such "non-traditional" tariffs. These sales represent about ten percent of Washington's non-DSI, total customer load and half of the state's non-DSI industrial load. All of these arrangements depart, to some degree, from the average cost basis on which fully bundled utility service rates have historically been set. Consequently, offering these new services presents the very real possibility that costs may be shifted among or within customer classes. Even if the new service is based on a more accurate and precise measurement of the costs to serve a specific customer, the new rate will likely depart from the average cost of serving all customers in the class and therefore may result in some level of cost-shifting. However, the new service may enable the utility to retain an at-risk customer (an industrial customer considering plant closure or cogeneration) which could have beneficial cost or other societal consequences for other customers.

It is important to recognize that these pricing arrangements may also have a different set of risks than traditional utility service. In particular, market prices for electricity are volatile. Consequently, the total rate paid by customers served by market-based tariffs varies through time, where the traditional, average cost service tariff is much more stable. Recent experience with fluctuating market prices from late 1996 through 1998 led all of the customers who originally chose Seattle City Light's market-rate tariff to return to traditional utility service. Washington Water Power's recent Direct Access demonstration offers another case in point. Customers who signed up for alternative supplier service early in the program when market prices were low realized benefits. But those who either waited until the second year of the program, or who only signed initial

Figure 4.1 Puget Sound Energy Schedule 48 Rate

Compared with Standard Schedule 49 Rate



contracts for one year, found market prices to be much higher, and they consequently stayed with the utility. As a final example, Puget Sound Energy's Schedule 48 market -based rate includes a power component indexed to market prices for power. Figure 4.1 compares the average total rate paid by all Schedule 48 customers compared to the rate they would have paid under the traditional tariff.

Market pricing may provide a benefit to some, but this benefit does not always come at the expense of other customers, particularly if it is accompanied by an increase in exposure to volatile market prices. On the other hand, if customers are allowed to switch back and forth between average cost and market-based service, depending on which is cheaper at any given time, regulators may find it difficult to avoid shifting costs to other customers. Price risk and whether it is actually borne by those customers who enjoy the benefits of market prices is a key factor the UTC and local utility regulators must consider when the cost and equity implications of a new service or pricing policy are considered.

4.4.2 Potential Magnitude of Cost-Shifts from Market-access or Market-based Pricing: Power Supply

To examine the potential for cost-shifts resulting from new retail power services and market pricing, we have estimated the magnitude of costs that might be shifted under a range of scenarios. These estimates are intended to "bound" what could be a cost-shifting problem. They do not make a prediction of what cost-shifting could or would actually occur, or whether and how these costs might be recovered in the rates of other customers.

The bounding analysis estimates the magnitude of current electricity generation cost that might be shifted to other customers if large volume customers obtain service at market-rates, or are granted direct access to utility delivery systems. This analysis depends strongly on three key estimates:

1) The total amount of load that goes to market pricing. We will refer to this as "competitive load".
2) The market price for power.
3) The cost for power embedded in utility rates. The embedded cost includes the cost of generation, demand side management and related taxes; but it excludes the cost of transmission and distribution.

If market prices are higher than embedded utility cost, the potential for existing power costs to be shifted from one set of customers to another is zero. The utility is either recovering more than its embedded cost (in the case of market-based pricing), or it can sell power at a market rate higher than its embedded cost (in the case of retail wheeling). If market prices are lower than the utility's embedded cost, the magnitude of potential cost-shifting is estimated as the difference between market prices and embedded cost times the amount of affected load.

Only one of these three key values, the embedded cost of utility power supply, can be known with any certainty, and then only for a snapshot in time. This value has been reported by the state's 12 largest utilities in response to HB2831 based on current costs. The competitive load that would choose market-based pricing is strongly dependent on the market price of power. While we have forecasts of market price for power, these future values are only estimates. Consequently, the bounding analysis hinges on a range of values for market price.

The utilities are one source of information about the three key estimates. As a part of the 6560 Utility Data Survey, utilities provided estimates of:

1) The load that might chose market pricing;
2) The load already being served at market pricing;
3) Any forecasts they have made of market prices for electricity.
4) Embedded power costs (HB 2831 reports)

In addition, we have market price forecasts from the Northwest Power Planning Council and the recent history of actual market prices since the establishment of price indices at California/Oregon Border, Mid-Columbia, and the California Power Exchange.[13] Based on these sources we picked a low, medium and high value to bracket market prices. These values cover the range from $19/MWh to $31/MWh. Actual average prices during 1998 have generally fallen within this range, with some departures substantially above the $31/MWh during late summer and early fall.

Using this information we have estimated the potential magnitude of cost-shifts based on the following logic:

1. If embedded cost of power for a utility exceeds the forecast market price, the competitive load is assumed to choose market pricing.

2. The magnitude of potential cost-shift is estimated as the competitive load times the difference between market prices and embedded cost, where the embedded cost is a weighted average of the costs allocated to the customer classes that make up the competitive load. This measures the "unrecovered" cost.

3. The effect of this potential cost-shift on remaining customers is calculated as a percentage increase in average cost per mWh based on current total costs (power generation and delivery). To examine the potential impact of a cost-shift, the analysis makes the *assumption* that 100% of the unrecovered cost is shifted to the remaining customers and recovered in their rates. For purposes of calculating this *potential* no assumptions regarding stranded cost recovery have been made.

Tables 4.1 and 4.2 present these estimates under the three market-price forecasts and two scenarios estimating the size of potentially competitive load. The first table (4.1) presents Scenario 1 and is based on the utility-provided estimates of competitive load. The second table presents Scenario 2: a "worst-case" view based on the arbitrary assumption that all industrial and large commercial load is competitive. The column labeled "proportion of state industrial and large commercial loads" depicts the percentage of the state's total industrial and large commercial load represented by the competitive load under each of the price forecasts.

In both competitive load scenarios, impact is measured both in terms of $/MWh and the percentage increase on total costs (power and delivery) that this would represent if it were shifted to the remaining load. These figures are averages for the state based on the 12 utility systems included in the analysis.[14] The "percentage increase" column also presents the range of utility specific figures around this average. Utilities fall within this range depending on the level of embedded power costs and the proportion of total load represented by the industrial and large commercial classes. For some utilities, the estimate of cost-shift potential is zero under all market price forecasts. For others, potential exists only under some of the forecasts, and for still others some potential exists across all of the market price range. Because of the number of assumptions involved and uncertainty about the actual size of competitive load, the statewide average estimates are more robust than are any estimates for individual utilities.

For Scenario 1, the proportion of industrial and large commercial load shifting to market-pricing ranges from 15 to 42 percent, depending on the market-price forecast. The statewide average impact of potential cost shifts ranges from less than 0.5 percent to 3.33 percent. The range around this estimated average impact is 0 percent to 13.1 percent. These impacts are relatively modest because of the state's relatively low-cost power generation. Based on market prices in the mid-$20/MWh range, the most likely impact is probably bracketed by the medium and high market-price forecasts, which represent the lower end of the ranges in these estimated impacts.

Table 4.1. Potential Magnitude of Cost-Shifts from Market-Based Pricing.
(Scenario 1. Utility estimates of competitive load)

Market Price ($/MWH)	Competitive Load (MWH)	Proportion of State Indust./Comm. Load	Unrecovered Cost (M$)	Impact ($/MWH)	Statewide Impact	Impact Range
19	10,708,640	42.4%	82.9	1.55	3.3%	0 to 13%
25	4,419,597	17.5%	30.5	.51	1.1%	0 to 3%
31	3,876,477	15.4%	6.0	.10	0.2%	0 to 0.5%

Estimate of competitive load from 6560 Utility Data Survey. Assumes no stranded cost recovery from competitive load. Total statewide industrial/large commercial load = 25,241 GWH. Does not include DSIs.

Table 4.2 presents Scenario 2. In this scenario, *all* industrial and large commercial loads are assumed to be competitive and to choose market-pricing if the market price is below utility embedded power cost. This is a larger estimate of potentially competitive load than in Scenario 1. Consequently, the estimated impacts are higher. This is particularly true for those utilities with a large share of industrial and commercial load. For Scenario 2, the proportion of industrial and large commercial load shifting to market-pricing ranges from 24 to 73 percent, depending on the market-price forecast. The statewide average estimate of impact on the costs for remaining customers ranges from 0.3 percent to 6.5 percent. The range around these averages is 0 percent to 25 percent. The higher end of this range occurs only in the lowest of the price forecasts and is driven by the effect of the arbitrary assumption that all industrial and large commercial loads choose market rates on utilities that have a large share of such loads. Again, because of the number of assumptions involved and uncertainty about the actual size of competitive load, the statewide average estimates are more robust than are estimates for individual utilities.

Table 4.2. Potential Magnitude of Cost-Shifts from Market-Based Pricing.
(Scenario 2. All Industrial and Large Commercial load assumed to be competitive)

Market Price ($/MWH)	Competitive Load (MWH)	Proportion of State Indust./Comm. Load	Unrecovered Cost (M$)	Impact ($/MWH)	Statewide Impact	Impact Range
19	18,395,455	72.9%	$137.5	3.00	6.4%	0 to 25%
25	8,443,155	33.4%	$50.4	.90	1.9%	0 to 5%
31	5,954,100	23.6%	$9.3	.16	0.3%	0 to 0.9%

Total statewide industrial/large commercial load = 25,241 GWH. Does not include DSIs.
Assumes no stranded cost recovery from competitive load.

Even beyond the preceding caveats to the analysis, several additional qualifications are necessary regarding the estimates in Tables 4.1 and 4.2.

First, it bears repeating that <u>these estimates are intended to bound the magnitude of cost that might be shifted – the potential for cost-shifting. They are not a prediction of what the magnitude will actually be, or whether any of these costs will actually be shifted. That is an issue in the hands of the utilities and their state and local regulators.</u>

Second, a number of factors could cause these estimates to be too high and a similar number could cause them to be too low. Some parties commenting on the draft of this report offered arguments for why they may be too high, and other parties offered arguments for why they may be too low.

Those who believe they are too high point out that mitigation of over-market power costs could be achieved through improved cost-efficiency, renegotiation of power purchase contracts, or other cost control measures. In addition, actions that capture the long-term market value of existing generation resources rather than their short-term value can reduce any gap between market-value and cost. The analysis is based on a “snapshot” of the difference between market value and cost. If costs are mitigated, the amount of cost that might be shifted is lower. In addition, one commentor noted that the average embedded power cost could actually decline if some customers choose to depart from bundled utility service. This could mean that, rather than costs being shifted, costs might be lowered for all customers. Finally, the analysis does not assume any provision for recovery of stranded costs from departing customers. If stranded costs are recovered from departing customers, there may be few if any costs left to be shifted. Snohomish County PUD commented that customers taking market priced power on its system were required to cover all costs. Consequently, the PUD states that market priced alternatives have produced no cost-shifting or cost-shifting potential in Snohomish County.

Finally, the estimates might be high because of data collection and analysis procedures. For example, when a utility provided a range of values for the possible competitive load, the analysis used only the highest value provided. If the market value of power is higher than estimated, or the average embedded cost for the competitive load is lower than reported, the load choosing competitive service may be smaller.than estimated and this would produce a smaller estimate of cost-shifting potential.

Those who believe that the estimates are too low also offered an impressive array of reasons. Many transmission and power purchase contracts, particularly those with BPA, contain a "take or pay" provision. When coupled with restrictions on the resale of power made excess by departing retail load, these take or pay provisions could leave utilities with power or transmission costs for which they cannot recover a market value. The analysis assumes that the potentially shifted costs are measured by the difference between the utility's embedded costs and market value. If the utility is prohibited by contract or law from recovering the market value it may be left with more costs to shift. Other commentors point out that the embedded cost of power reported by the utilities may in fact be erroneously low, and that this might lead to a larger estimate of both competitive load and a larger difference between embedded costs and market prices. The cost-basis for the power costs used in the analysis may not include all of the cost assigned to the power portion of rates and, consequently, some portion of distribution costs, A&G costs, or other overhead costs could be left with the utility to shift.[15]

Both sets of arguments have merit, but there is no way to judge whether considering all of those factors that might drive the estimates higher and all of those that might drive the estimates lower would lead to estimates that differ markedly from those we have made. Instead, we reiterate that this is an analysis intended to shed light on the potential magnitude of cost-shifting under the assumptions we have laid out. It is not statistically precise. It does suggest that under the assumptions we have used, the magnitude is modest: statewide less than 6 percent on the rates of remaining customers.

4.4.3. Loads Already Served With Non-Traditional Tariffs

The utilities also reported how much of their customer load was already served under market-based pricing or other non-traditional tariff service. Table 4.3 contains the loads reported by utilities as served by non-traditional tariffs as well as the proportion these loads represent of total industrial load.[16] This proportion is calculated for the utilities with non-traditional tariffs and for the state as a whole.

Table 4.3. Utility Industrial Load Served Under Non-Traditional (NT) Tariffs

(GWH)	1993	1994	1995	1996	1997
6560 Total	16,605	16,873	16,541	16,254	17,059
NT Utility Total(1)	14,398	14,419	14,155	14,120	14,647
NT Load	5,457	5,404	5,187	6,013	8,406
% State	32.3	32.0	31.4	36.9	49.3
% NT Utility	37.9	37.5	36.6	42.6	57.4

Does not include DSIs. Data from 6560 Data Survey covering 18 utilities and 89% of state total industrial load . (1) Seven utilities reported non-traditional industrial service: Cowlitz PUD, PacifiCorp, PSE, Seattle, Snohomish PUD, Tacoma Power and WWP.

The growing proportion of service under non-traditional tariffs suggests that some of the potential identified in Tables 4.1 and 4.2 may already have happened. However, the pressure to shift costs to other classes or customers implied by these existing pricing arrangements does not mean that costs have actually been shifted.

A record that rates have increased coincident with these pricing arrangements would provide at least circumstantial evidence of actual cost-shifting. The rate trends reported in Section 1.0 indicate that in Washington average industrial rates have increased over the last five years, as have average residential rates. For those utilities that offer non-traditional services tariffs, industrial rates are lower (under those tariffs) and the percentage of industrial load served under those tariffs has increased from 38 percent to 57 percent since 1993. The bulk of the increase in non-traditional service took place since 1995.

Table 4.4 examines the trends in rates between 1995 and 1997, for the state as a whole and for those utilities offering non-traditional pricing for industrial service. These figures include only those customers served by utilities and do not include the direct service industries served by BPA. Residential and commercial rates have remained virtually unchanged over this period, based on the statewide average and for the set of utilities offering non-traditional service. Industrial rates *declined* by an average of 5.5 percent for the state as a whole, but increased by a like percentage for those industrial customers taking traditional service from utilities that also offer non-traditional service.[17] As we noted in Section 1.0, this may represent increasing costs for the kind of industrial loads taking traditional service.

Table 4.4. Rates Statewide vs. Utilities with Non-Traditional Industrial Tariffs

	1995 Rate (c/kWh)	1997 Rate (c/kWh)	Change (c/kWh) (-)	Change (%) (-)
Statewide Rates				
Residential	5.01	5.01	0	0%
Commercial	4.81	4.82	.01	0.2%
Industrial	3.25	3.07	(.18)	(5.5%)
Utilities W/ NT:				
Residential	5.14	5.16	.02	0.4%
Commercial	5.05	5.06	.01	0.2%
Industrial (Trad.)	4.07	4.28	.21	5.2%
Industrial (NT)	2.61	2.60	,01	(0.4%)

Source: 6560 Utility Data Survey. Does not include DSIs.

Recent analyses covering the nation as a whole indicate that industrial rates have declined – in part due to new pricing arrangements – while residential rates have increased.[18] Table 4.4 demonstrates that, in contrast to national trends, there is little evidence that costs have been shifted to the residential or commercial classes in Washington. This comparison does not address the question of whether rates for these classes should have gone down at the same pace as the industrial class. Nor does it address the differences in risk between non-traditional service and traditional service to the industrial, commercial and residential classes.

4.4.4. Potential Magnitude of Cost-Shifts from Market-access or Market-based Pricing: Distribution and Delivery Services

Development of a competitive generation market and broad accessibility to price information from that market is also putting pressure on the distribution facility side of the retail electricity system. Some customers, again mainly large load customers, are showing growing interest in exercising their opportunities to bypass the local utility entirely.[19] This is not a new alternative; construction of redundant power delivery lines to access service from another utility has always been an option for customers who have practical opportunities to do so. The attractiveness of this option has increased, however, with transformation of the high voltage transmission system into an open-access common-carrier. Some utilities are also demonstrating growing interest in offering a competitive option to customers of neighboring utilities. Washington has no formally established utility territory boundaries other than those that the utilities themselves work out by contract (see Section 5.0). While there have yet to be significant examples of physical utility bypass and duplication of facilities, some examples are reportedly under consideration. In comments on the draft of this report Puget Sound Energy indicates that one of its large loads may be considering a project to interconnect with another utility.

The practicality and feasibility of distribution system bypass is very dependent on case-specific circumstances and subject to a variety of obstacles, including local land use, siting authorities, and the cost of bypass. One consequence of the threat of bypass is that utilities often attempt to discourage it by offering special pricing terms designed to retain the customer. Another is that it imposes discipline on the utility to keep its power *and distribution* rates low and to avoid customer class cross-subsidies. This competitive pressure can be beneficial if it lowers service costs to all the utility's customers. It can have adverse consequences if it discourages needed investment in distribution facilities, or discourages line extension investments to hook-up new customers in the utility's customary service area that would otherwise be justified by scale economies.

The consequence of a physical bypass is that some utility distribution facilities are duplicated. The embedded cost of these duplicated facilities is a cost that might be shifted to other customers. We have examined the potential magnitude of cost-shifts associated with physical bypass.

Similar to our estimates of the potential magnitude of power cost-shifts, we have relied on information provided by the utilities. As part of the information survey, the utilities were asked to estimate the amount of industrial load on their systems that might be able to exercise a physical bypass of distribution facilities. As with the power cost estimates, we have considered a range of market rates and assumed that bypass alternatives would only be exercised if the embedded power costs were greater than the otherwise available market price. This is an oversimplification for a number of reasons. But, it permits us to develop a rough estimate of the cost-shift potential from bypass.[20]

Based on the estimated bypass load potential and the embedded costs reported for power and delivery services reported by the utilities under HB 2831, Table 4.5 estimates the potential for distribution system costs to be shifted due to bypass. As with the power cost estimate, the purpose of this estimate is to provide an upper-bound on the size of the potential. And, as with the power cost estimates, no assumptions have been made regarding cost-mitigation or stranded cost charges. Because utilities and their regulators have it within their power to accomplish cost-mitigation and require stranded cost fees, <u>this is not a prediction or an estimate of what costs will actually be shifted.</u>

While the estimate is for delivery costs (i.e. wires cost), the load involved is also a subset of the power estimate. Those customers likely to exercise a bypass option are included in the set of customers who would choose market-base pricing alternatives. Consequently, the sum of the power cost estimates from Table 4.1 (or 4.2) and the wires cost estimates from Table 4.5 represents an upper-bound estimate for cost-shifting potential if customers choose market-pricing and those with bypass options exercise them. Table 4.5 presents the information and estimates on a statewide basis. Again, we have included the range of impacts across all 12 utilities included in the analysis. The statewide figures and average impact is a more meaningful and robust estimate than are estimates for individual utilities.

Table 4.5 presents estimates under the three market price forecasts used earlier. The column titled ”Bypass Load” is the estimate supplied by the utilities of load that could build a bypass to another system. Impacts are presented in both $/MWh and the percentage increase on the total cost for the remaining customers if the costs not recovered are shifted to their rates. The column labeled “Proportion of State Industrial/Commercial Load" represents the proportion of the state's total industrial and large commercial load that exercises bypass under each of the market price forecasts.

The estimated average statewide impact is small under all market price forecasts, ranging from 0.6 percent to 1.2 percent. The largest impact happens under the low price forecast, where nearly a quarter of industrial and large commercial load is affected. Under this case, the estimated impact on the costs for remaining customers ranges from 0 to 3.4 percent.

Table 4.5. Potential Magnitude of Cost-Shifts from Bypass.

Market Price ($/MWH)	Bypass Load (MWH)	Proportion of State Indust./Comm. Load	Un-recovered Cost (M$)	Impact ($/MWH)	Average Impact	Impact Range
19	5,961,689	23.6%	$33.5	.58	1.2%	0 to 3.4%
25	2,571,371	10.2%	$22.1	.36	0.8%	0 to 2.6%
31	2,127,000	8.4%	$17.7	.29	0.6%	0 to 1.6%

Estimate of bypass load from 6560 Utility Data Survey. Does not include DSIs,
Total statewide industrial/large commercial load = 25,241 GWH

4.4.5. Individual Customer Metering and System Management

This area covers a combination of power and delivery system issues. As new services including direct access are offered to customers, it becomes increasingly important to measure accurately both the magnitude of electricity usage and the timing of this usage for customers taking these services. It is important because these customers are either paying prices that are not based on average utility costs, or are receiving service from generation sources that are not the utility's or under the utility's direct control.

Traditional, average cost, utility service is provided through a local utility distribution system that is energized by the collective output of all of the utility's generation sources. The utility ensures that all use of electricity is matched with sufficient generation to keep all the lights on. Generation must be perfectly matched with load every second. This job is done by either the utility itself or a combination of utilities by operating a "control-area". Oversimplifying, traditional, average cost, utility service works because the average customer can be charged the average cost of all of the generation resources used to keep total generation in balance with total load. In reality, the utility's generation sources do not all cost the same and they are not all used all the time. But the utility does not need to match which generating unit was running with the electricity use of any particular customer so long as the average customer pays the average cost of all the generating units.

If competitive power suppliers serve some customers, and the utility does not closely track the usage of customers that are being served by these suppliers, cost-shifts could result in two ways. First, if the power supplier fails to deliver to the control-area the total amount of electricity that the open access customer actually used, the difference is automatically made up by the utility — since it, or its control area operator must keep generation in balance with load at all times. This is called an “imbalance” and if the utility is unable to determine through metering who caused an imbalance to occur it will be unable to charge the open access customer for the generation it supplied and the cost of this generation could be shifted to other customers. Second, the timing of any imbalance is very important because the cost of electricity generation as well as its market value varies depending on time of day. If an energy supplier delivers more power to the control area than its customer uses when the market value of power is low, and less power when the market value is high, the potential cost-shift from an imbalance is magnified. In fact, when calculated over a day or more the total customer use and total supplier deliveries could be in balance. But, if the time pattern is not metered, the utility may have been required to supply power during hours of imbalance when it is expensive and absorb excessive deliveries when it is cheap. The net cost to the utility may fall on other ratepayers if metering is not sufficient to identify these time patterns of imbalance.

These metering requirements are important regardless of the size of the customer usage. Deliveries of power into a control area over the transmission system can only be scheduled and tracked for transfers of 1 MW or more. Therefore, for any open access load to be accounted for within a control-area it must be at least 1 MW. If the 1 MW threshold is met with a number of aggregated sites, each must have metering sufficient to match usage of the aggregation with deliveries to the control-area boundary. Metering equipment is readily available to meet this need, but traditional utility meters are not sufficient because the measure only total energy usage and, in some cases, peak demand, not time of usage. Data are presented in Section 1.0 on the distribution of meter types and capabilities in Washington.

We have not attempted to estimate the potential magnitude of cost-shifts that might be caused by insufficient or inaccurate metering. However, it is revealing to note that the price of on-peak electricity sales at the Pacific Northwest trading hubs is often 50 to 100 percent higher than the price of off-peak sales.

4.4.6. Technology Change and Customer-Owned Generation

The opportunity for customers to construct their own generation facilities and displace most or all services provided by the utility has existed for decades. Customers make decisions to self-generate based on their costs to finance and construct generation facilities and purchase fuel. For the most part, examples of self-generation have been limited to large volume, usually industrial customers, who have their own source of fuel. Self-generation is relatively common in the pulp and paper industry where industrial by-products provide a fuel source and waste heat from generation can be used in on-site industrial processes. Technology development has improved the efficiency of self-generation and co-generation equipment, but because the customer must cover the full capital cost of such an installation it is unlikely that these opportunities will be as attractive as opportunities to gain access to market pricing through unbundled delivery services or physical bypass. Consequently, we do not believe that large scale self-generation adds greatly to the potential for cost-shifting in the state.

However, technology development in the area of small scale, localized generation, has advanced considerably in the last few years — particularly in the area of small fuel cells. Recent announcements of prototype equipment nearing commercialization indicate that fuel cell applications for small businesses, apartment buildings and even homes may only be a few years away. For example, both AVISTA Corporation and General Electric have recently reported research advances in small-scale fuel-cells and plans for commercialization of residential sized units in the next few years. BPA is reportedly also working on the demonstration of small-scale applications of fuel-cells. This is an important development for electric utilities because these small scale applications could mean that customers in the future will be able to replace utility service with their own, probably natural gas fueled, generation equipment. This would permit customers to completely disconnect from the utility grid leaving investments in utility generation, transmission and distribution that might be shifted to remaining customers. The timing of this technology development is not clear and the breadth of use of fuel cells or other small-scale local generation is today only a matter of speculation. However, widespread application could lead to significant cost pressures on local utilities and their regulators. Whether and how such costs might be shifted between customers is also unclear. But, it is nonetheless wise to consider that such a major shift in technology could undermine much of the justification and practical application of administratively established, average cost rates for utility distribution systems.

4.4.7. State and Local Taxes

State and local taxes are applied to utility sales as a gross revenue tax levied on the utility based on the gross revenue generated from retail electricity sales. The state tax is the Public Utility Excise Tax the revenues from which flow into the general fund. Local taxes are imposed by the municipality inside city limits and flow to the general-funds of the cities. Sales of electricity by out-of-state entities that are not otherwise engaged in the light and power business as an electric company in Washington do not generate taxable revenue at either the state or the local level. If utility services are unbundled and used to deliver power sold by out-of-state, non-taxable parties, both the state and affected local governments will lose tax revenue. This is potentially a cost shift if the lost revenue must be made up with charges or other taxes to other customers. Whether or not this would occur is uncertain and would be left to legislative decisions at the state or local levels.

The Department of Revenue (DOR) has prepared a briefing paper that examines tax-policy-related issues relevant to the electricity industry. DOR did not include any estimates of the potential lost tax revenues, in part because of the number of assumptions that would be necessary to make about the way power will be bought and sold and the location of customers and suppliers that may negotiate contracts. Faced with the same array of issues, we have not tried to make a tax-revenue-related estimate either. The DOR briefing paper offers a number of policy options for redesign of utility tax structure to fit with changes that may occur in the electricity industry. The paper describes the advantages and disadvantages of each. A copy is included in Appendix 4.1 of this report.

4.4.8. Conservation, Renewable Resource, and Low-income Program Costs

Most Washington utilities operate public purpose programs including conservation and low-income programs. These programs and their funding is the topic of another major section of this report (Section 9.0). For purposes of equity in utility rates and cost-shifting we have noted them here because they are a component of current utility rates that may not be included in special pricing arrangements, or that may be avoided altogether through open access or utility bypass. To the degree the programs are continued, their cost could be shifted between customers or customer classes.

4.5. Examination of Strategies Available to Minimize Cost-Shifts

This section describes an inventory of strategies and actions that may affect the potential for cost-shifts to occur. As noted earlier, there are no fully objective criteria for assessing whether cost-shifts are appropriate. So long as rates are set administratively, the responsibility to make judgements about whether rates are fair, just, reasonable and not unduly discriminatory or preferential will rest with the local rate-setting governments or boards, and with the UTC. For purposes of this evaluation we have assumed that some continuation of administrative rate-setting will persist even if policies to make retail electricity service competitive (open access) are adopted. This is because the delivery services will remain regulated and it is likely that some form of “default” or universal service options will need to be made available for customer classes for whom competitive options do not develop.

The strategies are organized into two categories. First, are those that may reduce the impact of some of the circumstances facing Washington’s retail utilities, the UTC, and the local jurisdictions responsible for rate setting that may lead to cost-shifting pressure. These strategies are categorized as <u>structural</u>. They include strategies affecting the wholesale and transmission sectors, as well as those affecting the introduction of competition to the retail service sector.

Second, are strategies addressing retail service rate-setting. These strategies are categorized as <u>administrative</u>. They include conditions or other requirements that might be placed on the rate-setting of the UTC and/or the local utility boards and commissions to prevent or reduce the likelihood of cost-shifting. In each case our purpose is to describe the strategy and the arguments for and against it, rather than to recommend a particular strategy or set of strategies.

4.5.1. Structural Strategies: Actions Affecting the Wholesale, Transmission, and Retail Service Sectors

1. Influence Development of Transmission ISOs to Minimize Cost-shifting in Transmission Pricing.

Description: Representatives of the state should participate in regional processes aimed at structuring management, access and pricing of the transmission system to prevent implementation of region-wide transmission tariffs that would result in cost-shifting.

Rationale: State interests are directly affected by the development of an ISO. The objective of participation is to add, where necessary, organizational improvements to our existing transmission system that further a competitive and reliable wholesale power market while avoiding transmission related cost-shifts.

Arguments For: If any ISO is ultimately proposed for the region, it will require approval from the FERC. The state will need to demonstrate that it participated actively in development of the proposal in order to be credible in defending state interests regarding cost-shifting and other issues in the FERC review process. In addition, state participation in regional transmission policy and organizations will bolster the case that state and regional interests should be included in ISO and reliability policy and not preempted at the federal level. Finally, some analyses indicate that the Northwest wholesale power market is already competitive and reliable under the current rate structure. Changes to this structure to accomplish a region-wide, average pricing could cause shifting with little or no additional benefit.

Arguments Against: State participation does little to add to the interests already well represented by the utilities. These interests may not be consistent since transmission affects different parties in different ways. The state could not establish a position that would avoid "choosing sides" among the utilities and other interest groups.

2. Influence Development of BPA Policy Regarding Allocation of Power and Pricing of Services.

Description: Representatives of the state participate in BPA processes with the objective of maintaining a financially viable federal power system that benefits the state and region, fulfills its environmental responsibilities, fulfills its public purpose responsibilities including affordable service in rural communities, and complements a competitive bulk power market, while at the same time minimizing pricing policies that result in cost-shifts.

Rationale: BPA's policies regarding pricing and terms and conditions for access to federal power and transmission resources are a critical component of electric power service costs in Washington. Changes in these policies will invariably have the affect of raising some parties' costs while lowering others.

Arguments For: The state can most effectively balance the competing interests of the various stakeholding parties within the state by influencing BPA on a government to government basis.

Arguments Against: There is no clear demonstration that BPA rate-making will necessarily result in retail cost-shifts. Participation by utilities and other interested parties is sufficient to represent state interests.

3. Preserve low-cost generation benefits for Washington customers.

Description: Actions include: strong defense in Washington D.C. of continued regional preference in access to cost-based power from the federal system, and preservation of the benefits of the low-cost generation of investor-owned and public utilities for the Washington customers of those utilities. The benefits can be kept in the region by having utilities retain ownership of the low-cost assets, or the net benefits can be assigned to customers after an asset sale. For investor-owned utilities, this can be accomplished by preserving the authority of the UTC to review, condition and approve "transfers of property" [Chapter 80.12 RCW] in the instance of sales of generation or utility mergers. For public utilities, the objective could be met with a clearly stated policy requiring that the net proceeds from the sale of publicly-owned generation assets or generation therefrom must be credited to utility customers.

Rationale: Washington's electricity generation base is, by most projections, lower in cost than would be its value if sold at market prices. In the absence of actions to preserve this benefit for Washington electricity customers, future developments could see these resources command prices based on market value with the consequence of increased electricity rates for Washington customers.

Arguments For: Preserves the benefits of the state's low-cost generation for Washington consumers regardless of the ultimate path of electricity wholesale and retail restructuring.

Arguments Against: No changes to current state law are necessary. Current law requires that the regulatory bodies of consumer-owned utilities review and approve any proposed sale of a generating asset and the disposition of proceeds from such a sale. The same provisions apply to the investor-owned utilities through the review and approval of the UTC in transfers of property.

4. Certification of distribution service territories.

Description: Establish geographically defined certificates describing the area in which an electric utility has the responsibility to provide distribution services to retail customers. As is the case in the local distribution gas industry, a certificate would be necessary to provide retail service. Certificates for a competing distribution company could be granted on demonstration that existing service is inadequate or that the competing service is otherwise in the public interest. Certificates apply only to electrical companies and do not prohibit private individuals from constructing facilities. Certificates do nothing to change the authority of municipalities or counties to choose to municipalize service through the establishment of a government-owned utility, or to condemn property for this purpose. Certification of distribution service territories would require new legislation.

Rationale: As described elsewhere in this report, Washington does not have distribution service territories established by certificate or franchise. This makes it difficult to establish who is responsible for serving a given customer, particularly where utility boundaries established by custom or history intersect. State policy discourages competition in utility wires and delivery service (RCW 54.48.020). Yet in the absence of defined service territory responsibilities duplication of facilities can occur and lead to facility costs being stranded if bypassed and potentially shifted to other customers.

Arguments For: Establishment of distribution service territories clarifies service obligations and provides for an orderly examination of circumstances where one utility can more cost-effectively provide service to the customer of another. This examination can identify any costs or compensation due between utilities, or the utility and a customer, and avoid some pressures to shift distribution facility costs.

Arguments Against: Reducing the uncertainty and risk associated with bypass (for the utility) reduces the competitive pressure to keep distribution costs low. Establishment of distribution service territories does not address all bypass or self-generation issues and, in fact, does not even apply when connection or generation facilities are privately constructed. State approval of service certificates or franchises would adversely affect the ability of municipalities and other public entities to exercise statutory authority to expand or create new service territory through condemnation or annexation. State authority to repeal a certificate threatens the local control of utility service. Finally, it would be inconsistent for the state to be creating new monopolies for service territories as the electric utility industry begins to face competition.

5. Establish a Competitive Class of Service (Partial Open Access)

Description: Based on size-of-load or other characteristics establish that some customers have access to use of the distribution system as a common carrier for delivery of power from whatever power supplier they choose. Metering standards would be necessary to ensure that the usage of such competitive access customers could be distinguished from the remainder of the utility's loads. Such competitive service is similar to the "transportation tariffs" available for natural gas customers who wish to purchase their own natural gas supplies. As is the case with these natural gas tariffs, the terms and conditions for competitive service and "re-entry" to utility service would be clearly established. Utilities could offer such services under current law, but new legislation would be necessary to require that the service be offered.

Rationale: Some customers are equipped and prepared to accept the risks and reap the benefits of arranging their own power sources. Clearly establishing the terms and conditions for these customers to arrange for market-based power supplies and conditions for the use of utility delivery systems provides for a more orderly treatment of costs that might otherwise be shifted to other customers or customer classes.

Arguments For: Responds to the desire of some customers to take responsibility for resource supply and price risk in return for potential benefits of market access. Provides for a more orderly allocation of risks, responsibilities and obligations between the utility and its customer classes. Prevents risk from being shifted from competitive customers to core customers of the utility. Allows for a focused calculation of any responsibility for past utility investments and any qualifications necessary to the utility's future obligation to provide service.

Arguments Against: May be difficult to control customers migrating back and forth between competitive and non-competitive service in order to capture the lower of market or cost-based pricing. This can lead to political pressure to breach protections against cost-shifting, particularly when the customer loads are large and economically important. Requires either a prohibition on utilities providing both cost-based, bundled service and competitive power services, or a difficult to enforce regulatory "fire-wall" between these services.

6. Establish Open Access to Competitive Power Supplies for All Customer Classes (Full Open Access)

Description: Establish that all customers have the opportunity to make their own selection of power supplier with the power delivered over the utility's, common-carrier distribution system. This is full retail wheeling and would transform the utility's current "obligation to serve" to an "obligation to connect". Terms, conditions, and rates for the use of the distribution delivery services would continue to be regulated. Full open access requires metering sufficient to separately account for every customer's usage pattern. Utilities could offer open access tariffs on their own decision, but legislation would be necessary to require that all utilities offer such service.

Rationale: If all customers have access to competitive power services there is no administrative pricing for these services and therefore no opportunity for administrative pricing decisions to shift costs.

Arguments For: Removes any possibility of administrative cost-shifting, at least for power services, and eliminates the complication of regulating the boundary between competitive and non-competitive services that can be a problem in partial open access. Permits all customers to choose power supplier, services, price and risk based on individual preferences. Clarifies utility role as "obligation to connect" with no obligation to provide power services. Provides for focused determination of customer responsibility for past utility investments.

Arguments Against: Competitive markets may not develop to serve all customer classes. Power marketers may concentrate efforts on larger load customers. Some universal or "default" service might be necessary to require of the utility and shifts in risk and cost between this service and competitive service would be similar to the boundary problems described for partial access. Customers may not have equal access to the information and capital necessary to make effective market choices and they may not be interested in understanding or taking on the responsibility to make these choices. Additional costs would likely be incurred by the delivery utility (or some other body) to maintain individual customer metering and necessary accounting to allow for billing settlements. Allocation of these costs to customers could involve cost-shifts or other inequities.

7. Maintain current regulatory system including UTC regulation of investor-owned utility retail rates and local regulation of consumer-owned retail utility rates with a legislative policy statement that discourages cost-shifting and utility distribution bypass.

Description: Maintain cost-of service regulation of retail utility service with flexibility for the UTC and local regulators to approve and implement utility services and rate structures, including unbundled or other competitive services as appropriate and if in the public interest.

Rationale: Establishes a state policy discouraging cost-shifting and distribution bypass while maintaining the capability of the UTC and local regulators to manage utility service consistent with the public interest and local utility circumstances.

Argument For: Maintains the flexibility of the current well-functioning system to adapt to local circumstances and local values. Does not impose a "one-size-fits-all" solution on utilities and customers. Requires no major structural reforms. Does not put the utility tax base at risk and does not force customers into undeveloped new markets.

Arguments Against: Does not guarantee that UTC or local regulators will not cause costs to be shifted inequitably. Does not establish a common and uniform set of rules for competitive electricity services and utility obligations. Does little to remove the uncertainties and risks that may cause utilities to make decisions that shift costs or risks among customers.

4.5.2. Administrative Strategies: Strategies and Actions Affecting Retail Service Rates

1. Legislative prohibition of cost-shifting.

Description: The legislature could prohibit any regulatory decision to change rates charged to customer classes or customers within a class that causes those customers to be responsible for costs they are not responsible for in rates today and which were formerly paid by other customers or customer classes. The prohibition would apply to the UTC as well as the public utility rate-setting bodies. This strategy would require new legislation.

Rationale: Cost-shifting is the result of administrative decisions to shift the responsibility for cost recovery from the rates of one customer or customer class to the rates of another. Prohibiting the rate-setting bodies from doing this prohibits cost-shifting.

Arguments For: Establishes a clear, unequivocal policy that cost-shifting is not permitted by the utility or by its rate-setting regulator.

Arguments Against: The complexity and imprecision of cost-of-service studies makes it unlikely that all but the most egregious incidence of cost-shifting could be identified definitively. This approach assumes that all current cost allocations are perfect and removes the flexibility to respond to changing circumstances from the regulator or local jurisdiction whose responsibility is also to ensure that sufficient revenue is generated to maintain reliable service. Such a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

2. Rate Freeze.

Description: Prescribe that residential and small commercial rates must be frozen, or rise at no more than some established rate of increase, over some period of time. This approach was taken in California (for investor-owned utilities) as part of the state's industry restructuring. This strategy could be implemented by the UTC and local jurisdictions, but a uniform state policy would require new legislation.

Rationale: Freezing rates prohibits the utility, or its rate-setting body, from increasing the rates of one customer or class in order to lower the rates of another.

Arguments For: Provides protection against rates being raised for one customer or class of customers in order to lower rates for another. Straightforward to administer — rates don't change from what they are today.

Arguments Against: Removes flexibility from regulator and local jurisdictions to respond to changing circumstances including costs and other issues that may be out of their control. This approach assumes that all current cost allocations are perfect. May discourage needed investment in infrastructure, new generation resources, and public purpose programs, and lead to deterioration in service quality or reliability. Such a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

3. Relative Rate Gap Caps

Description: Prescribe that the current relative comparison between residential, commercial, and industrial rates remain fixed regardless of how overall rates for all classes change in the future. For example, if residential rates for a utility are 50% higher than industrial rates, this percentage is held constant if industrial rates change. This strategy would be difficult to implement in legislation because the circumstances of each utility are different. The strategy could be implemented by the UTC or local jurisdictions without new legislation.

Rationale: Cost of service studies have established rates for the various customer classes that bear a proportional relationship to one another. So long as this relationship is maintained, no matter what changes are made to the rates charged to one or another of the classes, costs have not been shifted to one class in order to reduce them for another.

Arguments For: Provides the same kind of protection as the rate freeze, but allows for flexibility for the utility, regulator, or local jurisdiction, to respond to changing cost circumstances that affect the utility's overall revenue requirement.

Arguments Against: The "gap caps" must assume that the components of service cost remain constant between the customer classes and that all current cost allocations are perfect. Cost increases could be associated more with one class than another (for example, undergrounding of residential class distribution lines). Maintaining a strict "gap cap" could result in unfair distribution of costs between the classes. In addition, if industrial or other large load rates are indexed to competitive power prices, a strict implementation of the gap cap introduces significant price volatility and risk to residential rates. Gap caps will not be consistent between utilities because of differing customer base and cost structure and these differences could lead to confusion and controversy. Finally, a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

4. Performance Based Rate-Making

Description: Prescribe that utility rates be based on performance standards rather than strictly on cost of service. So long as utilities achieve the specified performance standards, permit pricing to individual customers or classes of customers to be flexible within a ceiling and a floor. For example, rates could be set no higher than a ceiling set at historical cost adjusted for inflation and a floor no lower than the long run marginal cost of providing the service. This strategy would be difficult to implement in legislation because the circumstances of each utility are different. The strategy could be implemented by the UTC or local jurisdictions without new legislation.

Rationale: So long as the cost-basis for the rate ceiling for any class is fair, just and reasonable, the utility's ability to flexibly price below the ceiling for some customers does not shift costs to others or constitute undue discrimination. This approach is similar to the rate-freeze except that in provides the utility with downward pricing flexibility and an incentive to improve cost-efficiency, and the regulator with the flexibility to establish other performance requirements like service quality or cost-efficiency targets.

Arguments For: Allows both the utility and regulator the flexibility to respond to changing circumstances and to include a focus on performance standards other than rates. Diminishes the "cost plus" inefficiencies of traditional cost-based rate-making by mixing cost-based pricing principles together with incentives for the utility to capture cost-efficiencies in serving any of the classes. Capturing these cost-efficiencies permit it to either enjoy better earnings or compete with price discounts to more price sensitive customers.

Arguments Against: Pricing flexibility may lead to claims of price discrimination tantamount to cost-shifting. Determining the floor for pricing flexibility may be difficult. Pricing and performance standards could be complex, difficult and expensive to develop and monitor for the regulator or local jurisdiction. If not set high enough, a ceiling on rate levels could discourage or prevent needed investment for power supplies or reliability. A one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

5. Specify and Define Uniform Stranded Cost Recovery Responsibility

Description: Costs for power or delivery services not recoverable by a utility that offers services at market rates or that loses a customer to open access service are calculated and recovered from customers choosing non-embedded cost based services. Stranded costs could be evaluated using administrative calculations based on market price projections, or via a market valuation based on auction sale of the power or delivery facilities. Whichever approach is used, the cost recovery is limited in time and the costs to be recovered should be mitigated through cost-efficiencies, or contract reformation. The later is the approach taken in the gas industry when federal regulation of the interstate pipelines was changed to no longer require the pipelines to maintain dedicated reserves. This is an administrative step that would have to accompany the structural alternatives of partial or full open access listed above. It may also require clarification of distribution service territory issues. The UTC and local jurisdictions have the authority to implement stranded cost recovery on wires delivery services administratively. The authority to implement "exit fees" where wires service is no longer taken is problematic for both the UTC and the local jurisdictions.

Rationale: The utility incurred costs in order to provide service to all customers. If some customers choose to leave service in favor of another source of power supply or in favor of market pricing, the utility can recover its investment from these customers rather than shifting the cost to others, or to the utility shareholders.

Arguments For: Ensures that, if all historical costs embedded in utility revenue requirements are collected, they are not disproportionately collected from some customers or customer classes via a cost-shift. In the event that stranded costs are negative (a benefit), uniform treatment across customer classes ensures that these benefits are returned equitably to all customers. Policy providing for the equitable recovery of stranded costs also ensures that the security interest in public debt issued by public utilities is not undermined.

Arguments Against: The magnitude of stranded costs to be recovered is not simple to calculate — at least not for power costs. It depends on the relationships among market prices for power, existing fixed and operating costs of utility power, potential cost mitigation and assumptions about discount rates. If calculated based on an *administrative* estimate, the value is vulnerable to the inevitable errors in forecasting these factors. Stranded costs could be determined to be a large value based on forecasts made today and turn out to actually have been smaller or zero if the forecast undershot the actual market price. The reverse is true if the forecast overshoots the actual market price. Alternatively, an auction sale of power resources can establish a true *market valuation* of their worth. However, this is also a snapshot in time and could similarly lead to customers being made responsible for stranded costs when there actually were none, or no stranded costs when they actually prove to have been large. Finally, contract reformation as a cost mitigation may result in legal disputes regarding the statutory context within which the contracts were established (e.g. PURPA contracts). This could undermine the credibility of power contracts in the future.

6. Terms and conditions for exit and reentry to average rates.

Description: Establish terms and conditions that customers must meet in order to leave average rate service and in order to return to such service after having left. Such terms and conditions might include: sufficient metering capability to separate a customer's load shape from the remainder of the utility's loads; payment of stranded costs; customer willing to provide or compensate the utility for back-up service; customer responsible to pay any incremental costs to re-enter averaged rate service. Some Washington utilities including Grant County PUD have established such terms and conditions. This is an administrative step that would have to accompany the structural steps of partial or full open access listed above. This strategy would likely benefit from legislation to clarify service territory issues and obligation to serve issues.

Rationale: Removing a customer from the pool of customers served at the average cost to serve the pool has both cost and operational implications. Clearly establishing terms and conditions will ensure that existing costs are not left with the remaining customers and that new costs are not incurred by the remaining customers.

Arguments For: A clear set of rules and requirements for open access, or some other form of competitive pricing, makes it clear for those who might choose such service what they need to consider. And, it makes matters clear for those remaining on traditional utility service how they are being protected from cost and risk shifts.

Arguments Against: May be administratively, legally and politically complex. Administrative difficulties might include such issues as change of ownership, or change of site functions. Legal difficulties may involve clarification of obligation to serve issues. Political sustainability of these terms and conditions could be difficult if adverse economic or employment impacts result from poor market decisions by the customer.

7. Establish Uniform Responsibility for Conservation, Renewable Resources, and Low- income Programs

Description: For those public purpose programs to be accomplished through collective funding and action (e.g. low-income weatherization, bill assistance, some forms of conservation and renewable resources, universal service, etc.) a charge is placed on electricity service that applies to all customers. This strategy is further discussed in Section 9.0.

Rationale: Public purpose programs are undertaken to achieve enunciated state policy objectives. In the absence of a non-avoidable charge which applies to all customers, the cost of achieving the programs — many of which are currently included in utility rates — could either be shifted to, or fall disproportionately on one customer group or another.

Arguments For: Ensures that all customers contribute equally to programs that are deemed to be important to be funded collectively from utility services. Ensure that programs are funded in a competitively neutral way.

Arguments Against: These objectives and policies could more appropriately be supported through general tax revenues. To the extent one customer class might pay more for public purposes than the benefits they receive, a cost-shift will occur.

Endnotes for Section 4

1 This risk is not really a new cost. In the past, utilities have been responsible for building new generation capability adequate to meet growing demands. The cost of ensuring that demand was met under all load conditions is included in average utility rates. This means that rates are higher than the cost of producing electricity when loads are not near peak levels. The consequence of average-cost rates is that all customers contribute to the cost of ensuring adequate resources are available to meet all customer loads at all times — that is, the risk of new resource costs is shared by all customers.]

2 Possible Effects of Competition on Electricity Consumers in the Pacific Northwest. Hadley, Stan and Hirst, Eric. Oak Ridge National Laboratory. January, 1998. ORNL/CON-455. Power Markets in the U.S. Resource Data International. Boulder, Colorado. January 1997.

3 Possible Effects of Competition on Electricity Consumers in the Pacific Northwest. Hadley, Stan and Hirst, Eric. Oak Ridge National Laboratory. January, 1998. ORNL/CON-455.

4 Comprehensive Electricity Competition Plan. Rate estimates for the WSCC/NWPP in 2010. U.S. Department of Energy. March 25, 1998

5 See Are customers of Northwest utilities likely to pay higher electricity rates due to competiton? Northwest Power Planning Council.

6 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

7 Analysis done by UTC staff.

8 See for example H.R. 4432 entitled Electric System Reliability Act of 1998 introduced by Representatives Delay and Markey August 6, 1998.

9 See for example, Electric Competition Revolution: The Sequel". Remarks of James Hoecker, Chairman, Federal Energy Regulatory Commission. Sixth Department of Energy and National Association of Regulatory Utility Commissioner's National Electricity Forum. Houston, Texas, September 17, 1998.

10 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

11 These ten or so large industrial plants are predominately aluminum smelters. In the past, they have accounted for as much as 25 percent of total FCRPS sales.

12 Washington Rural Electric Cooperative Association.

13 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

14 The estimates were compiled for the state's twelve largest utilities only because these are the only utilities from whom current data on power costs are readily available from HB 2831 reports. These utilities comprise roughly 85% of the state's total electricity sales and more than 90% of the non-DSI industrial and large commercial sector sales.

15 For example, some public utilities are debt-free, but none-the-less recover new distribution facility costs in power rates. This situation could be remedied by assigning and recovering these costs on distribution.

16 Non-traditional service to applies generally to "large loads". These are not necessarily synonymous with "industrial loads" . In some cases large commercial class loads qualify for non-traditional service.

17 Had we been able to include 1998 data the overall industrial rates and the rates for non-traditional service might have shown an increase since these rates are now tied to market prices and 1998 market prices were higher than in previous years.

[18] The Changing Structure of the Electric Power Industry: Selected Issues, 1998. U.S. Department of Energy. Energy Information Administration. July, 1998.

[19] The amount of distribution services used by large customers varies from utility to utility, but for the most part large customers use less distribution and are assigned less distribution costs than is the case for smaller volume customers.

[20] This simplification ignores both the cost of constructing the bypass and the potential that a neighboring utility might have power costs below the market price. These factors have opposing effects — the first causes an overestimate of bypass potential and the latter an underestimate. Both of the factors are driven by individual circumstances and, without a detailed analysis of every industrial customer near the borders of all utilities, there is no practical way to improve the accuracy of the assumption.